FORECASTING OF OIL AND GAS RESERVOIRS

[1]P Vannuru Swamy, [2]T Anil Kumar
[1]Research Scholar.
[2] Sr asst professor, Dept. of Petroleum Engineering,
[1,2] Aditya Engineering College Surampalem, East Godavari, Andhra Pradesh.

Abstract : Oil and gas reservoir has a long life cycle, from the discovery of hydrocarbons to the complete exploitation of reserves. The stages in the life of hydrocarbon reservoir are discovery, evaluation, development, production and abandonment. After the field discovery, the delineation of field is done, where few wells have been drilled and the reserves are estimated. in development of reservoir, more wells are developed to exploit the remaining reserves. development of reservoir is based on the production data of existing producing wells, their PVT analysis data, logging data, well test data etc. when the hydrocarbon production rate is non economical then the reservoir is abandoned.

We can calculate the oil/gas initially in place, the type of drive mechanism involved, recovery factor, drainage radius and we can predict the future production trends of existing wells using volumetric method, material balance method, decline curve analysis and well test analysis of different types of reservoirs calculate the permeability and skin factor and radius investigation etc.

In this paper, we discussed three case studies wherein reserves estimations and production prediction for these sands of sand – w, sand – d, sand – g , sand – c, for newly drilled well, well test analysis is carried out. material balance method, decline curve analysis and p/z plot was used for estimating the parameters like OIIP, GIIP, water influx (we) and ultimate reserves, permeability, skin factor and also using these methods production prediction was done.

1. INTRODUCTION

The development of oil/gas reservoir, first a reservoir is to be discovered by wildcat drilling like exploratory well based on seismic interpretation, if it gives the show of the some interesting zone like hydrocarbons and the reservoir field is sufficiently large to accumulated hydrocarbons which are economically viable to exploit, the field can be developed to economically the remaining volume of hydrocarbon to enhance the recovery and optimize the production of the reserves based on its economic viability.

We found different reservoir parameters and properties using to core sampling and reservoir fluid sampling. Sampling is of two types: subsurface sampling and surface sampling. Well testing is done through build up and draws down study to know the various reservoir parameters like Reservoir Pressure, Skin Factor, Permeability, which are used in Reserves Estimation. PVT analysis is carried out to determine different parameters like Oil formation volume factor (B_o), Gas formation volume factor(B_g), solution gas oil ratio(R_s), API gravity and bubble point pressure of sample (P_b). From core sampling, porosity and saturation data is obtained. In development there are some conditions to be reached,

a) Wells should be spaced so as to have minimum interference between adjoining for producing oil and gas

b) Reservoir energy to be utilized to the maximum to achieve maximum recovery.

c) The cost of the development reservoir should be minimum, as much as possible.

The following studies to be carried out:

- Prepare a geological model and Estimation of oil/gas reserves
- Indicate number of locations where wells are to be drilled to produce hydrocarbons
- To make performance prediction for about 5- 15 years, the amount of oil, gas and water production on daily and yearly basis, behavior of pressure over time, the position of oil water contact etc
- Indicate the self flow period and when it is necessary to install artificial lift mechanism for production
- Necessity of pressure maintenance or application of enhanced methods of recovery

2. Wild Cat Drilling or Exploration – Field Discovery

Exploration depends on highly sophisticated technology to detect and determine the extent of these deposits using geophysical methods of exploration. To discover a suitable structure for the presence of hydrocarbons geological and geophysical surveys like **gravity, magnetic, seismic surveys** are carried out. By this a structure is identified with the help of seismic interpretation, if structure is sufficiently large so as to give economically viable reserves of hydrocarbons, a location for drilling of an exploratory or wild cat well is planned in an attempt to confirm and determine the presence or absence of oil or gas zone.A significant amount of geological and seismic investigation must first be completed to redefine the potential hydrocarbon drill location from a lead to a prospect. Four geological factors have to be present for a prospect to work and if any of them fail neither oil or gas will be present.

The seismic method is rather simple in concept. An energy source (dynamite, vibrators, air gun) is used to produce seismic waves (similar to sound) that travel through the earth to receivers, on land, or pressure, at sea. The receivers convert the motion or pressure variations to electricity that is recorded by electronic Instruments.

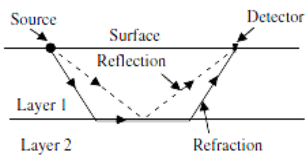


Fig 2.

There are 3 steps cquisition, data processing and data interpretation. Sub –surface formations are mapped by measuring the times required for seismic wave, generated in the earth by near surface explosion of dynamite, mechanical impact. Reflections from depths as great as 20,000 ft can normally be observed from a single explosion, so that in most areas geological structures can be determined throughout the sedimentary section. The data recorded from one shot at one receiver position is referred as seismic trace, and is recorded as a function of time. The wanted information is called as signal(S) and the unwanted information is called noise (N).

In the process of data acquisition, there are many sources and receivers situated at different locations. Each has occupied a particular position on the ground this information is essential to identify, which geophone was recorded by which shot. All this information I s recorded in the trace header, which is used during signal processing. It is useful in gathering traces belonging to same common midpoint, common offset, common receiver point etc. also the dead and live traces are also included in the trace header so that invalid traces can be bypassed during course of processing to save the computer time. The data processing enhances the S/N ratio to get the data which enables geological interpretation. In the interpretation we identify structures such as anticlines, faults, reefs, salt domes etc.

2.4 Objective of Reserves Estimation

The Objective of stock taking of reserves is mainly for strategic planning exploitation. It is carried out for new discoveries or in new promising structures on prognosticated basis for long term planning.

i. Reservoir type
ii. drive mechanisms
iii. Quantity and quality of the geological, engineering, and geophysical data
iv. Assumptions adopted when making the estimate
v. Available technology
vi. Experience and knowledge of the evaluator.

The period during which reserves are estimated to design specific types of plan are.

i. Prior to drilling and development
ii. Just after drilling and completion
iii. At-least after one year production data is available
iv. When the production is declining

3. Classification of Reserves

For an oil or gas deposit to be classified as reserves. It needs to establish technical and commercial certainty of extraction using existing technology.

- Proved Reserves defend 90% Certainty of Commercial Extraction
  - Proved Developed reserves PD
  - Proved Undeveloped reserves PUD
- Unproved Reserves
  - Probable reserves
  - Possible reserves

3.1 Proved Developed reserves PD

Proved Developed PD reserves are expected to be recovered from existing wells. Improved recovery reserves are considered only when additional investment is low

3.2 Proved Undeveloped reserves PUD

proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally. Proved Undeveloped PUD reserves are expected to be recovered from new well or when relatively large expenditure is required to install production facilities

3.3 Unproved Reserves

Unproved Reserves are less certain to be recovered than proved reserve and may be sub classified as probable or possible to denote progressively increasing uncertainty. Value of probable reserves is not the recoverable reserves. Due to its low reliability, it is not considered for commitment purpose

3.4 Probable reserves

Probable Reserves $\Rightarrow$ 50% Certainty of Commercial Extraction

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable reserves.

3.5 Possible Reserves

Possible Reserves $\Rightarrow$ 10% Certainty of Commercial Extraction

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

4. Studies to Know Characteristics of Reservoir

Logging

Logging is the Logs are used to define physical rock characteristics such as lithology, porosity, pore geometry and permeability. Logging data is used to identify productive zones, to determine depth and thickness of zones to distinguish between oil, water and gas in the reservoir, to estimate the hydrocarbon reserves and also geological maps developed from log interpretation help with determining relationship and drilling locations. the one mostly used is open hole type logging where logs are recorded in the uncased portion of the wellbore. There different types of logs are used to the oil industry

4.4 Nutron Log

The neutron log is sensitive mainly to the amount of hydrogen atoms in a formation. Its main use is in the determination of the porosity of a formation. The scattering reactions occur most efficiently with hydrogen atoms. The resulting low energy neutrons or gamma rays can be detected, and their count rate is related to the amount of hydrogen atoms in the formation

5. PVT Analysis:

PVT analysis is very important tool of reservoir engineers to find out the oil formation factor Bo, gas formation factor Bg and gas oil ratio GOR. This properties act like the conversion factors of the surface to sub surface. The main purpose of the analysis to predict the bubble point pressure of reservoir. We use two processes for this flash liberation and differential liberation.

Compositional analysis of the separator oil and gas, for samples collected at the surface, together with physical recombination, compositional analysis of the reservoir fluid collected in a subsurface sample. Such analyses usually give the mole fractions of each component up to the hexanes. The hexanes and heavier components are grouped together, and the average molecular weight and density of the latter are determined. These parameters are used for estimation of reserves and for reservoir engineering calculation

5.1 Collection of fluid sample

Samples of the reservoir fluid are usually collected at an early stage in the reservoir's producing life and dispatched to a laboratory for the full PVT analysis. There are basically two ways of collecting such samples, either by direct subsurface sampling or by surface recombination of the oil and gas phases.

5.2 Sub surface sample

A special sampling bomb is run in the hole, on wire line, to the reservoir depth and the sample collected from the subsurface well stream at the prevailing bottom hole pressure. Either electrically or mechanically operated valves can be closed to trap a volume of the borehole fluids in the sampling chamber. This method will obviously yield a representative combined fluid sample providing that the oil is under saturated with gas to such a degree that the bottom hole flowing pressure pwf at which the sample is collected, is above the bubble point pressure. In this case a single phase fluid, oil plus its dissolved gas, is flowing in the wellbore and therefore, a sample of the fluid is bound to have the oil and gas combined in the correct proportion.

5.3 Surface sampling

In collecting fluid samples at the surface, separate volumes of oil and gas are taken at separator conditions and recombined to give a composite fluid sample. The well is produced at a steady rate for a period of several hours and the gas oil ratio is measured in scf of separator gas per stock tank barrel of oil. If this ratio is steady during the period of measurement then one can feel confident that recombining the oil and gas in the same ratio will yield a representative composite sample of the reservoir fluid.

6 . Reservoir Drive Mechanism:

For a proper understanding of reservoir behavior and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behavior of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically driving mechanisms that provide the natural energy necessary for oil recovery:

6.1 Depletion Drive mechanism:

The principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble point pressure, gas bubbles are liberated within the microscopic pore spaces.

Characteristics	Trend
Reservoir pressure	Declines rapidly and continuously
Gas–oil ratio	Increases to maximum and then declines
Water production	None
Well behavior	Requires pumping at early stage
Oil recovery	5% to 30%

Table: 6.1. 1 Characteristics of depletion drive mechanism

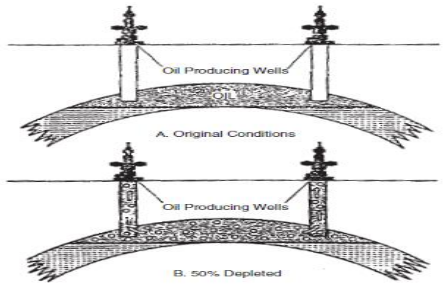
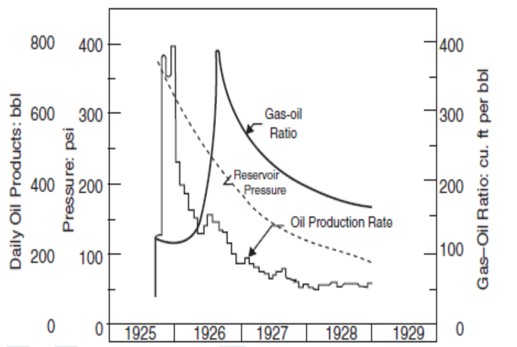


Fig 6.1.2: Solution gas drive reservoir



Graph 6.1.1: Production data for a solution gas drive reservoir

6.2 Gas Cap Drive:

Gas cap drive reservoirs can be identified by the presence of a gas cap with little or no water drive as shown in Figure.

Characteristics	Trend
Reservoir pressure	Remains high
Surface gas–oil ratio	Remains low
Water production	Starts early and increases to appreciable amounts
Well behavior	Flow until water production gets excessive
Expected oil recovery	35% to 75%

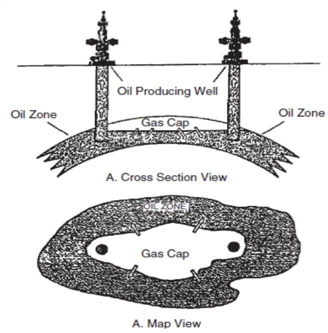


Fig 6.2.1: Gas cap drive reservoir

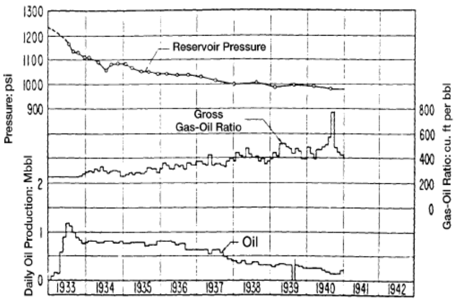
The natural energy available to produce the crude oil comes from the following two sources:

(1) Expansion of the gas cap gas, and

(2) Expansion of the solution gas as it is liberated.

Characteristics	Trend
Reservoir pressure	reservoir pressure falls slowly and continuously
Gas–oil ratio	The gas–oil ratio rises continuously in up structure wells.
Water production	negligible water production.
Well behavior	moderate
Oil recovery	The expected oil recovery ranges from 20% to 40%.

Table 6.2.2: characteristics of gas cap drive



Graph 6.2.3: Production data for a gas-cap-drive reservoir.

6.3 Water Drive Mechanism:

Many reservoirs are bounded on a portion or all of their peripheries by water-bearing rocks called aquifers. The aquifers may be so large compared to the reservoir they adjoin as to appear infinite for all practical purposes, and they may range down to those so small as to be negligible in their effects on the reservoir performance.

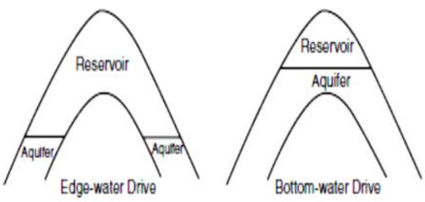
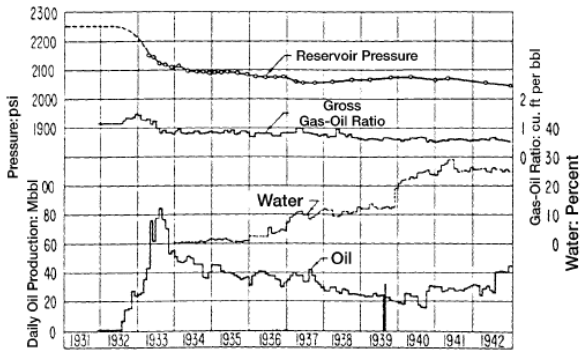


Fig 6.3.1: edge water and bottom water drive

It is common to speak of edge water or bottom water in discussing water influx into a reservoir. Bottom water occurs directly beneath the oil and edge water occurs off the flanks of the structure at the edge of the oil as illustrated in Figure. Regardless of the source of water, the water drive is the result of water moving into the pore spaces originally occupied by oil, replacing the oil and displacing it to the producing wells.



Graph 6.3.3: Production data for a water-drive reservoir.

7. Estimation Of Reserves:

Estimation of hydrocarbon reserves is done to know the quantity of oil or natural gas present in the reservoir.

7.1 Volumetric Method:

The method is widely used at all stages for oil and gas reservoirs. Formula for estimation of reserves

For oil reservoirs:

$$N = \frac{A*H*\emptyset*(1-Sw)\rho o}{Bo}$$

Where,

- N=oil reserves in million tons (MMT) at stock tank conditions.
- A=oil bearing area, Km².
- H= effective thickness of pay zone, MTS.
- Ø=effective porosity, fraction.
- Sw = water saturation, fraction.
- B_0=formation volume factor for oil.
- ρ_0=specific gravity of oil.

It is apparent that the necessary parameters are determined from geological model, H, porosity and water saturation from electro logs or from cores and formation volume factor from PVT reports or from standard correlations.

7.2 Material Balance Method:

The material balance technique mathematically models the reservoir as a tank. This method uses limiting assumptions and attempts to equilibrate changes in reservoir volume as a result of production.

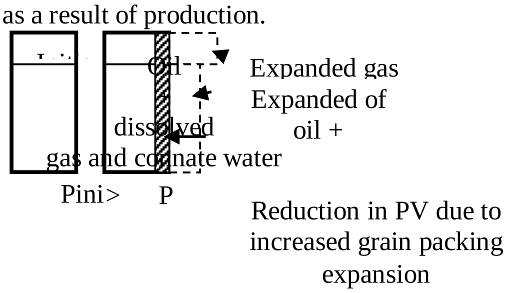


Fig 7.2.1: assumptions of material balance method

Change in pore volume = change in oil volume + change in free gas volume + change in water volume

Change in pore volume = $\frac{N*Boi*Cf*P}{(1-Swi)}$

Change in oil volume $= N * B_{oi} - (N - Np)B_{oi}$

Change in free gas volume $= (GBgi - Gbg) + (Np\,Rp(N - Np) - NRsi)Bg$

Change in water volume $= -\frac{NB_{oi}Swi}{(1-Swi)}CwP - We + WpBw$

Where,

- B_g = formation volume factor of free gas
- B_{gi} = formation volume factor of free gas at initial conditions
- c_f = formation (rock) compressibility (psi^{-1})
- c_w = water compressibility (psi^{-1})
- N = OOIP (STB)
- Np = cumulative oil produced (STB); from production history data
- P = Change in reservoir pressure due to production, that is, initial pressure minus current pressure; taken from field pressure surveys
- R_p = cumulative gas-oil ratio, or total produced gas (in SCF)/ total produced oil (in STB); from production history data
- R_{si} = initial solution gas-oil ratio (SCF/STB)
- S_{wi} = initial connate water saturation (decimal)
- W_e = cumulative amount of water encroachment; from map and field data
- W_p = cumulative water produced; from production history data
- Another general equation is

Were, $N = \frac{Np[Bt+(Rp-Rsi)Bg]-(We-Wp*Bw)}{(Bt-Bti)+\left(\frac{M*Bti}{Bgi}(Bg-Bgi)\right)+\frac{Bti(Cw*Swi+Cf)P}{1-Swi}}$

- B_t = total (two-phase) formation volume factor
- B_{ti} = total formation volume factor at initial conditions
- M = gas cap size expressed as a fraction of initial reservoir oil volume; from map data

Material balance estimation for gas:

The material balance technique for calculating gas reserves, like material balance for oil, attempts to mathematically equilibrate changes in reservoir volume as a result of production

The basic equation

Weight (or SCF) of gas produced = weight (or SCF) of gas initially In the reservoir – weight (or SCF)of gas remaining in the reservoir.

Gas reservoir with active water drive:

$$G = \frac{Gp*Bg-(We-Wp*Bw)}{Bg-Bgi}$$ were,

Gp is cumulative gas production

We water influx

Wp cumulative water production

MBE as an equation of straight line: the over all material balance is

$Np\,[Bo+(R_p-R_s)\,B_g] + W_p.B_w = N\,[(B_o-B_{oi})+(R_{si}-R_s)\,Bg] + mNB_{oi}\left(\frac{Bg}{Bgi}-1\right) + NBoi\,\frac{(m+1)}{1-Swi}\Delta P\times(Cf+Swi\times Cw) + We + W_{inj}.B_w + G_{inj}B_{gin}$

Havlena&Odeh expressed the above equation in a condensed form as-

$$F = N[E_o + mE_g + E_{fw}] + (W_e + W_{inj}.B_w + G_{inj}.B_{ginj})$$

For the purpose of simplicity, assuming that no pressure maintenance by gas or water injection then the above relationship can be simplified and written as

$$F = N[E_o + mE_g + E_{fw}] + We$$

The terms F, E_o, E_g and E_{fw} are defined by-

F represents the underground withdrawal and given by –

$F = N_p[B_o+(R_p-R_s)B_g]+W_pB_w$

In terms of two phase formation volume factor Bt, the underground withdrawal, F, can be written as

$F= N_p\,[B_t+(R_p-R_{si})\,Bg\} + W_pB_W$

Eo is the expansion of oil and its originally dissolved gas is expressed in terms of-

$Eo = (B_o-B_{oi}) + (R_{si}-R_s)B_g$

In terms of B_t-

$E_o=B_tB_{ti}$

E_g is the expansion of the gas cap gas and is given by-

$E_g=B_o\left[\left(\frac{Bg}{Bgi}\right)-1\right]$

In terms of two phase formation volume factor, $B_{oi} = B_{ti}$

$E_g = B_{ti}\left[\left(\frac{Bg}{Bgi}\right)-1\right]$

E_{fw} represents the expansion of the initial water and reduction of pore volume is given by-

$E_{fw} = B_{oi}\frac{(m+1)}{1-Swi}\Delta P\times(Cf+Swi\times Cw)$

Havlena & Odeh examined several cases of varying reservoir types with equation and pointed out that the relationship can be rearranged into the form of a straight line.

7.3 Decline Curve Analysis:

Decline curves are one of the most extensively used forms of data analysis employed in evaluating gas reserves and predicting future production. The decline curve analysis technique is based on the assumption that past production trends their controlling factors will continue in the future and, therefore can be extrapolated and described by a mathematical expression

The methods of extrapolating a trend for the purpose of estimating future performance must satisfy the condition that the factors that caused changes in past performance, for example decline in the flow rate will operate in the same way in the future. These decline curves are characterized by 3 factors.

i. Initial production rate or the rate at some particular time.

ii. Curvature of the decline.

iii. Rate of decline.

Arps empirical rate/time decline equation is the most conventional decline curve analysis

$$q(t) = \frac{q_t}{(1+bD_it)^{Y_b}}$$

- Where, D_i= Initial decline rate ($days^{-1}$)

b= Arps decline curve exponent

- q_t =Gas flow rate at time t, MMSCF/day
- q_i= Initial gas flow rate, MMSCF/day
- t= Time, days.

The three different forms of decline are based on the value of the decline exponents b. these three forms of decline exponential, harmonic and hyperbolic have different shape on Cartesian and semi-log graphs of gas production rate versus time and gas production rate versus cumulative gas production.

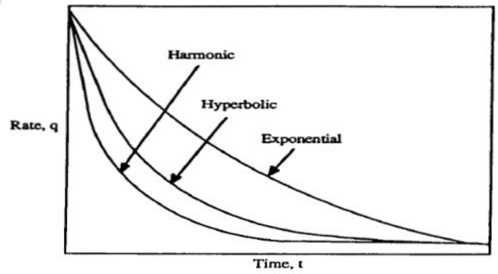


Figure 7.3.1: Decline curve shapes for a Cartesian plot of rate Vs time

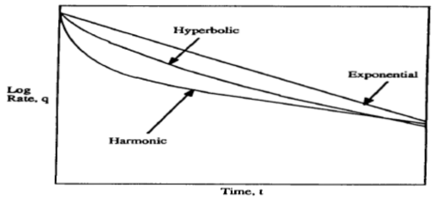


Figure 7.3. 2: Decline curve shapes for a semi-log plot of rate Vs time

Consequently, these curve shapes can help identify the type of decline for a well and, if the trend is linear, extrapolate the trend graphically or mathematically to some future points.

Figure 1 &2 show typical responses for exponential, hyperbolic and harmonic declines. Because of their characteristic shapes, these plots can be used as a diagnostic tool to determine the type of decline curve before any calculations are made.

Exponential decline

Exponential decline, sometimes called as constant percentage decline, is characterized by a decrease in production rate per unit time that is proportional to the production rate.

$$\operatorname{Log} q(t) = \log(q_i) - \frac{D_i}{2.303 q_i} G_p(t)$$

Hyperbolic Decline:

When 0<b<1, the decline is hyperbolic, and the rate behavior is described by-

$$q(t) = \frac{q_i}{(1 + bD_i t)^{\frac{1}{b}})}$$

Expression for cumulative gas production in terms of gas flow rate during hyperbolic decline-

$$G_p(t) = \frac{q_i b}{D_i(b-1)} \left[q(t)^{1-b} - q_i{}^{1-b}\right]$$

Hyperbolic decline never has a simple straight line relationship for either rate Vs time or rate Vs cumulative production plots on any co-ordinate system.

CASE STUDIES

Case Study 1

Objective: To determine Oil Initial In Place (OIIP) and W_e (Water Encroachment / Water Influx) for sand -W using existing PVT data, wells production data.

In Sand -W four wells have been drilled and are under production from Jan 1998 to till date. Using the PVT data and production data Oil Initial In Place (N) and W_e (Water Influx) are calculated by material balance method and decline curve analysis.

Reservoir and PVT Parameters:

The PVT data for wells are,

well name	Bo	h, meters	Ø	So
WELL- 6	1.23	5	0.25	0.72
WELL- 9	1.15	5	0.27	0.7
WELL- 15	1.24	5	0.23	0.8

Table -1.1: PVT data for well

The PVT Parameters of sand 18-W,

Rsi	Rs	Rp	Np	Wp
102	102	90	978	279.74
102	102	90	33863	14236.22
102	102	113	36590	14900.12
101.3	101	211	63130	27042.02
93.5	92.6	198	132668	57550.13
91.6	89.7	118	191733	94358.01
90.3	88.4	125	641372	337115.07

Table-1.2: PVT parameters of sand-w

Bubble point pressure = 2375 psi. = 167 ksc

Maps Interpretation:

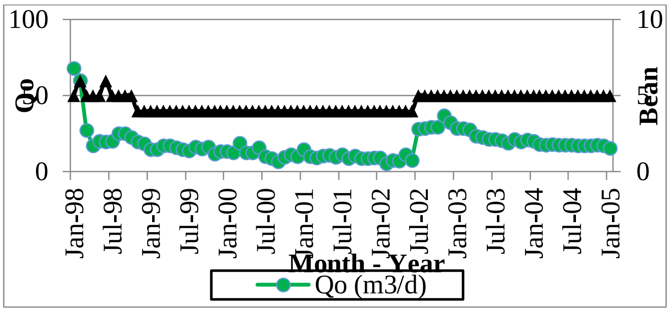
Structure Contour Map and Isobar Map of Sand -W are drawn.

From Contour Maps, reservoir continuity is observed and well placement is indicated, it also enables to calculate reserves and monitor trends in reservoir performance.

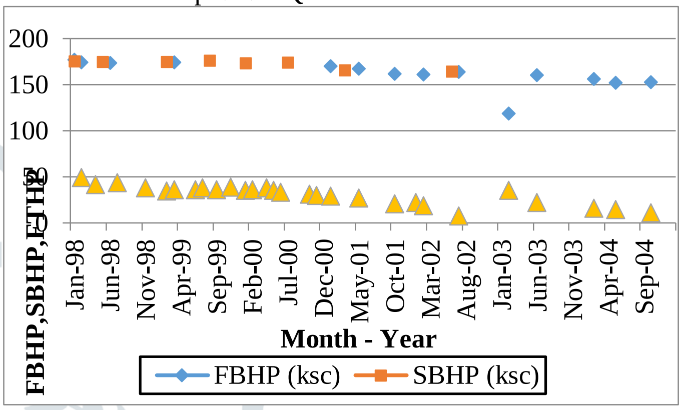
Well Performance Analysis:

The graphs are plotted between Qo vs Bean vs Time, GOR vs Time, Qo, Qg, FTHP vs Time, FBHP, Qo vs Time, for all the wells to see their Production Behaviour.

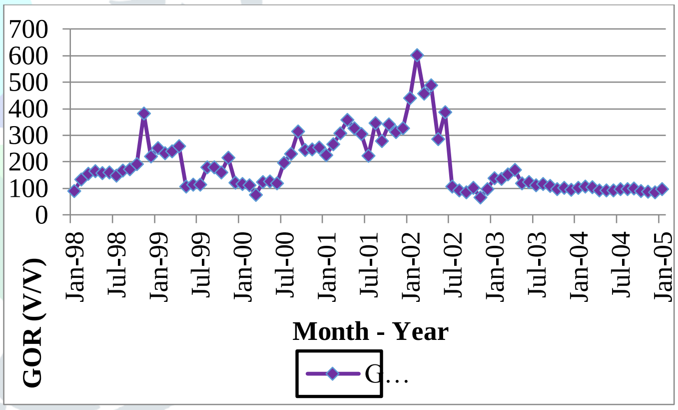
WELL –2



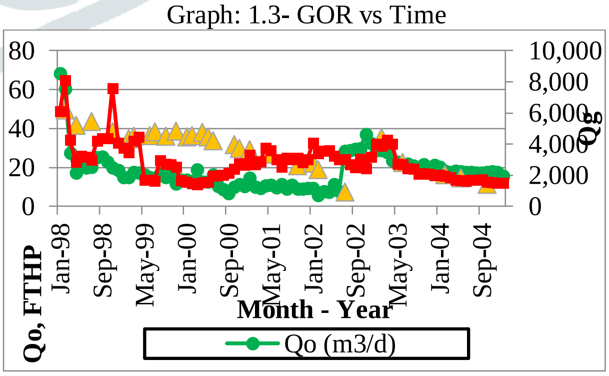
Graph: 1.1- Qo vs Bean vs Time



Graph: 1.2 – FBHP, SBHP, FTHP vs Time

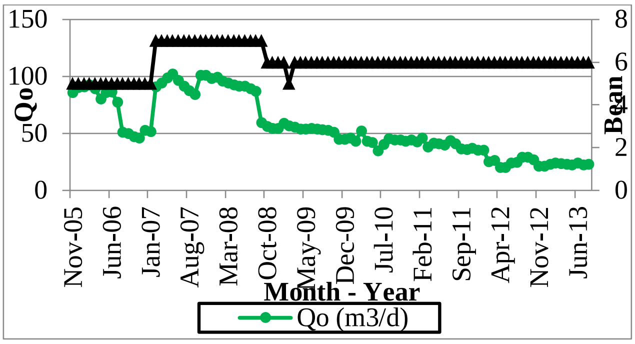


Graph: 1.3- GOR vs Time

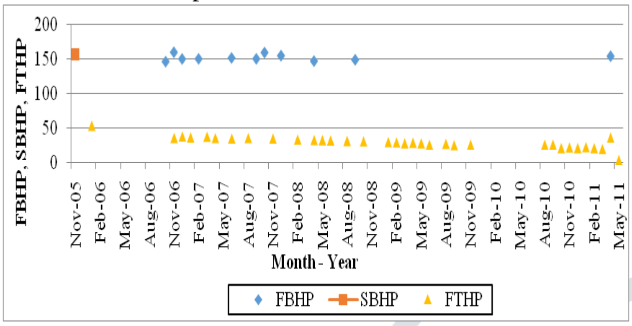


Graph: 1.4 – Qo, FTHP vs Qg vs Time

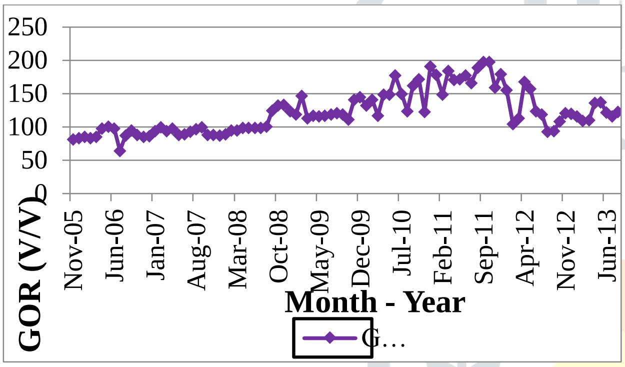
From Well Performance graphs of WELL - 2 we observed Flowing Period is from Jan – 98 to Jan – 05. From Graph:2 we observed less fall in FBHP, that indicates reservoir is under water drive mechanism.



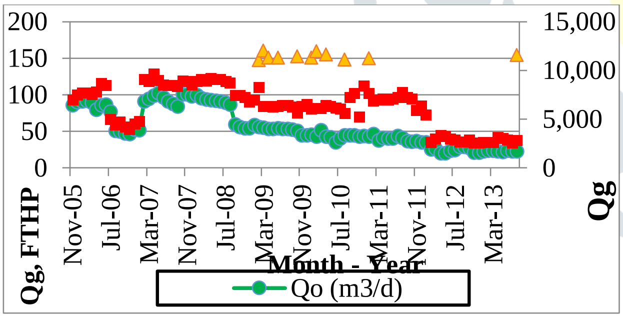
Graph: 1.5- Qo vs Bean vs Time



Graph: 1.6 - FBHP, SBHP, FTHP vs Time



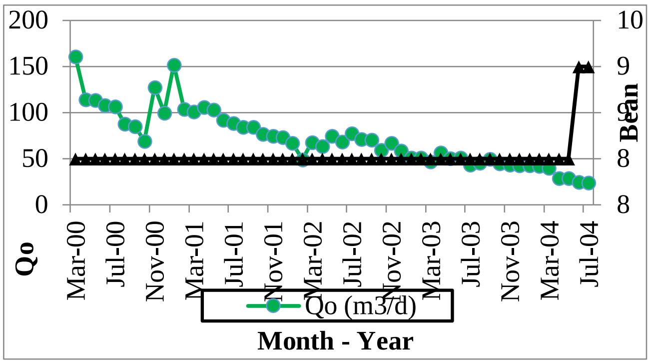
Graph: 1.7 - GOR vs Time



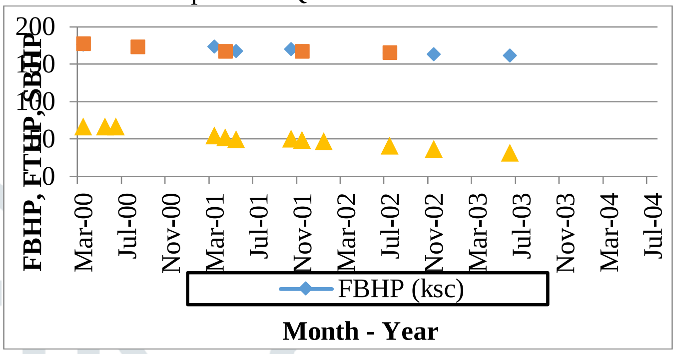
Graph: 1.8 - Qo, FTHP vs Qg vs Time

From the above Graphs, WELL-6 flowing Period is from Nov – 05 to Jun – 13. From Graph:6 we observed, less fall in FBHP, that indicates reservoir is under water drive mechanism.

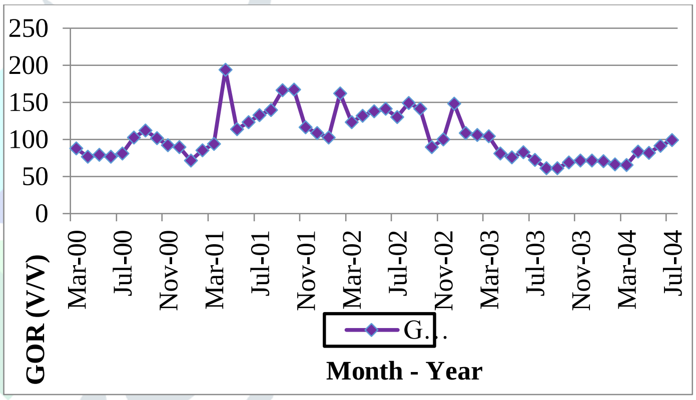
WELL 6



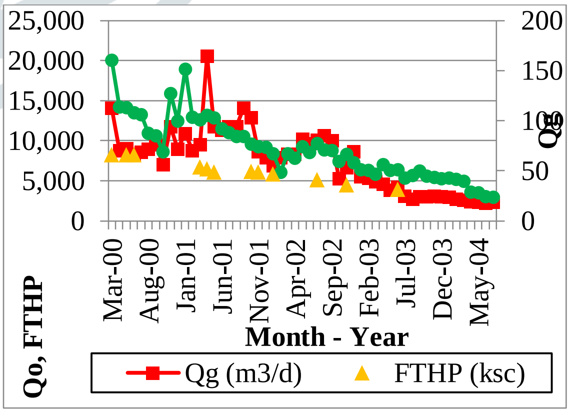
Graph: 1.9 - Qo vs Bean vs Time



Graph: 1.10 - FBHP, SBHP, FTHP vs Time

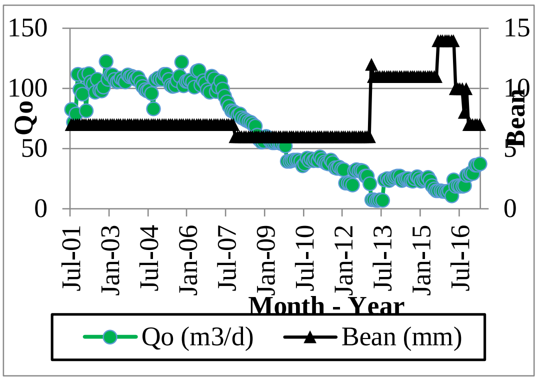


Graph: 1.11 - GOR vs Time

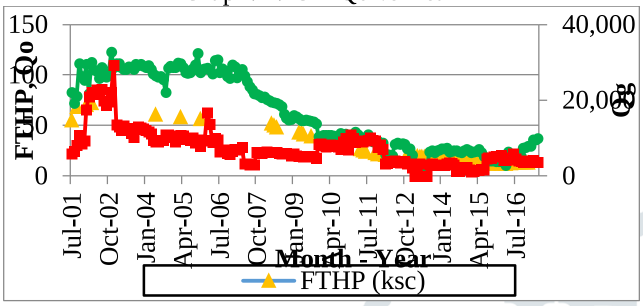


Graph:1.12 - Qo, FTHP vs Qg vs Time

From the above Graphs, WELL-9 Flowing Period is from Mar 00 to July 04. It can be observed from graph:10 FBHP is constant. Fluctuations in GOR can be observed from Graph



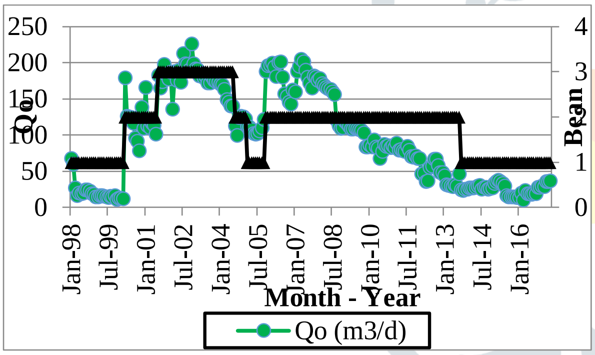
Graph: 1.13 – Qo vs Bean



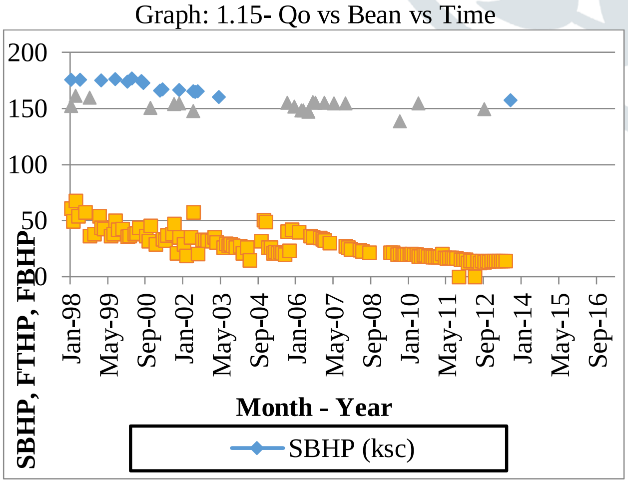
Graph: 1.14- Qo, FTHP vs Qg vs Time

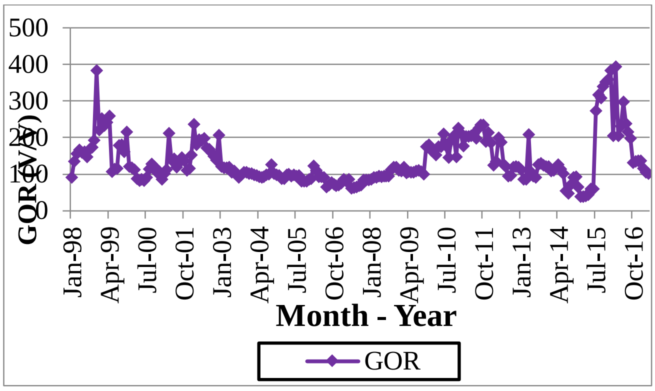
From the above Graphs, WELL-15 is Flowing till Date. From Graph:15, it can be observed GOR Fluctuations due to the Oil Production fluctuations. It is observed from Graph:14 FBHP (Reservoir Pressure) gradually drops. So, not active water support is observed from Graph:16.

Sand -W

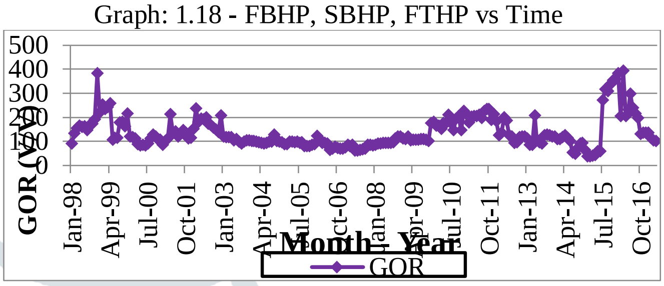


Graph: 1.15- Qo vs Bean vs Time

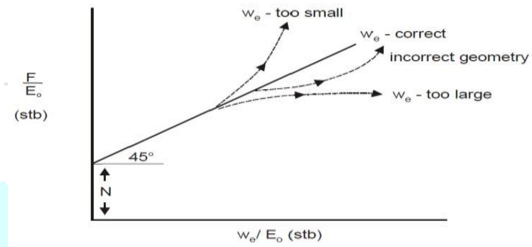


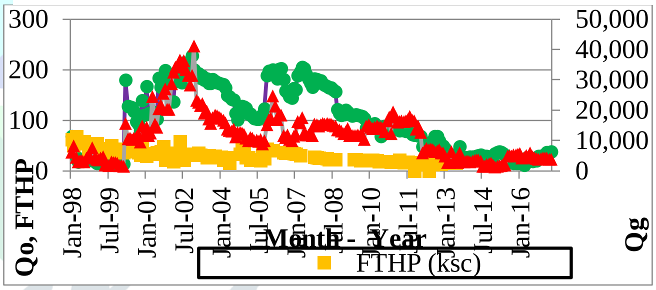


Graph: 1.18 - FBHP, SBHP, FTHP vs Time



Graph: 1.19 - GOR vs Time





Graph: 1.20 - Qo, FTHP vs Qg vs Time

From above Graphs of SAND -W, from pressure and performance trend, we observed that with time the reservoir pressure is declining gradually. GOR is increasing gradually.

Reserves Estimation:

The primary drive mechanism in Sand -W reservoir is **Water drive.**

The PVT Parameters of sand -D

SBHP (PSI)	FBHP (PSI)	ΔP (PSI)	Boi	Bo	Bg= (ZT/P)*0.02 827
2501.2 98	2434.4 64	66.8 34	1.45 63	1.44 82	0.006940639
2482.8 12	2518.3 62	35.5 5	1.47 69	1.46 45	0.006992316
2458.6 38	2482.8 12	24.1 74	1.48 61	1.47 17	0.007061067
2373.3 18	2379.0 06	5.68 8	1.46 23	1.45 18	0.00731491
2346.3	2332.0 8	14.2 2	1.40 21	1.39 12	0.007399142
2280.8 88	2292.2 64	11.3 76	1.36 28	1.36 18	0.007611337
2235.3 84	2236.8 06	1.42 2	1.36 55	1.36 11	0.007766275

Table-1.21: PVT Parameters of sand -D

Input Data

Reservoir Temperature = 230^0 F

Formation Compressibility C_f = 3.32 X 10^{-6}

C_w = 7.22 X 10^{-5} psi

To Evaluate N

Using the technique of Havlena and Odeh (assuming that Bw = 1), the material balance can be expressed as $F = N_p (B_o + B_g (R_p – R_s)) + W_p$

To calculate B_g Gas Formation Volume Factor

$B_g = \frac{ZT}{P}\ 0.02827$

Consider Z = 0.89; T = 230^0 F = 230 + 460 = 690^0 C

$B_g = \frac{0.89\ x\ 690}{2501.298}$ x 0.02827 = 6.9406 x 10^{-3}

$B_g = \frac{0.89\ x\ 690}{2482.812}$ x 0.02827 = 6.9923 x 10^{-}

Graph 1.22: F/E_0 Vs W_e/E_o

Now evaluating $F = N_p\ (B_o + B_g (R_p – R_s)) + W_p$

At 2501.298 SBHP (PSI)

F = 978 (1.4482 + 0.006940639 (90-102)) + 279.94 = 1614.6242

At 2482.812 SBHP (PSI)

F = 33863 (1.4645 + 0.006940639 (90-102)) + 14236.22 = 60987.21

$E_o = (B_{oi} + B_o) + B_g (R_{si} - R_s)$

At 2501.298 SBHP (PSI)

Eo = (1.4563 – 1.4482) + 0.006940639 (102 – 102) = 8.1 x 10^{-3}

At 2482.812 SBHP (PSI)

E_o = (1.4796 – 1.4645) + 0.006992316 (102 – 102) = 0.0124

F =Np(Bo+Bg(Rp - Rs))+Wp	Eo = (Boi - Bo)+Bg (Rsi - Rs)
1614.624258	0.0081
60987.21379	0.0124
71591.63175	0.0144
169491.0818	0.012694473
345581.588	0.017559228
396759.4576	0.01546154
1392393.711	0.019155923

Drainage Area (A_D) = $\frac{EUR\ x\ B_o}{\emptyset\ x\ h\ x\ S_o\ x\ R_f}$ = $\frac{641372\ x\ 1.3611}{0.27\ x\ 7\ x\ 0.7\ x\ 0.3}$ = 2199474.5 m^2

Πr^2 = 2199474.5, r_o = 836.9 m

$r_{aq} = \left(\frac{230944822.5}{3.14}\right)^{0.5}$ = 2711.997 m

Reservoir Volume = A x h = 2199474.5 x 7 = 15396321.5 m^2

$\frac{\text{Reservoir Volume x 15}}{10}$ = 23094482.25

$W_e = (C_w + C_f) \times Ø \times h \times \pi \times f \times (r_{aq}^2 – r_o^2) \times \Delta P$

$= (7.22 \times 10^{-5}) + (3.22 \times 10^{-6}) \times 0.27 \times 7 \times 3.14 \times 1 \times (2711.977^2 – 836.9^2) \times 66.834$

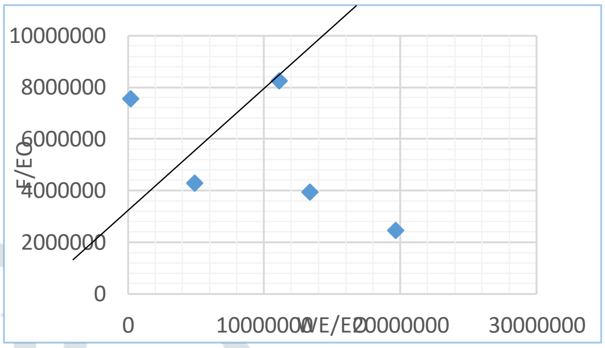
= 284749.4553

We = Cw+Cf*Ø*h*π*(Raq2 - Ro2)*ΔP	F/Eo	We/Eo
284749.4553	199336.3282	35154253.75
151462.4762	4918323.693	12214715.83
102994.4838	4971641.094	7152394.712
24233.9962	13351565.11	1909019.487
60584.9905	19680910.29	3450322.02
48467.9924	26944112.31	4535646.653
6058.49905	72687374.02	316272.8924

F/Eo	We/Eo
199336.3282	7534613.481
4918323.693	4283792.347
11101741.09	8240983.507
13351565.11	3917330.738
19680910.29	2445853.387

Considering f (Water Encroachment Angle) = 0.5, increasing reservoir volume V_r 10 Times, , increasing ΔP by 20%

A plot between F/Eo and W/Eo is drawn



Graph 1.23: plot between F/Eo and We/Eo

If the aquifer model is correct, A Straight line with slope of 45^0 and joining two or more data points is drawn and We/Eo = 0. If the aquifer model is incorrect, the plotted data points will deviate from the theoretical straight line which has a slope of 45° and intercept N, when We/Eo = 0,

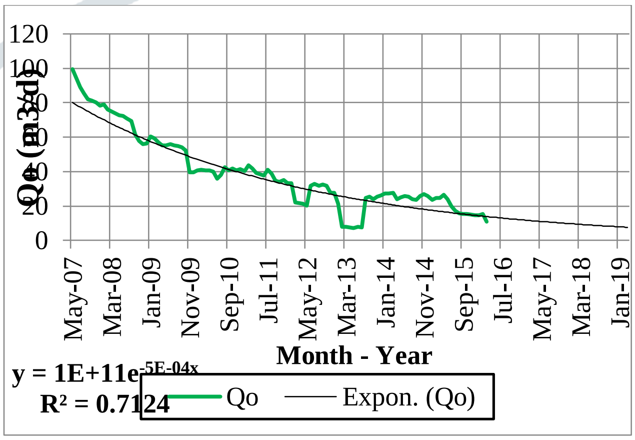
Hence the N = 1.2 MMT = 1200000 tons

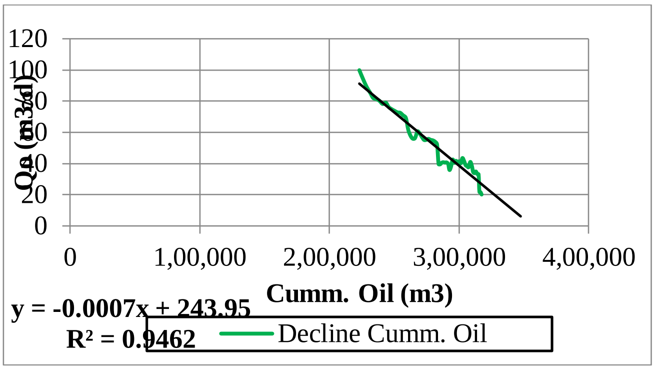
Water Drive Water Drive Recovery Factor is 60 %. So, by considering this N = 0.72 MMT = 720000 tons

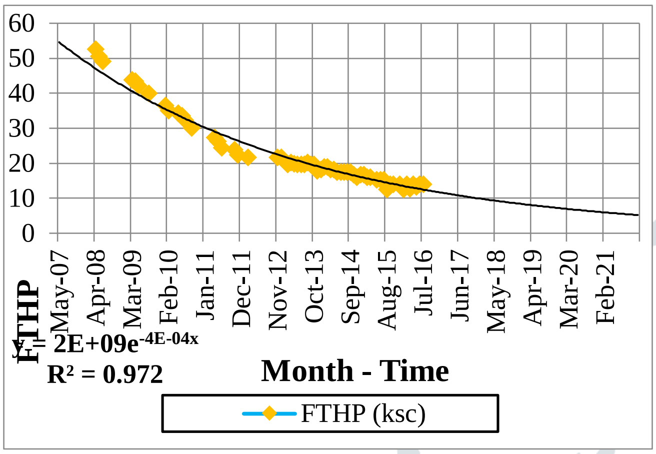
Sand -W can be further exploited, sufficient reserves were present. 0.72 MMT

Production Profile – Decline Curve Analysis (Exponential):

Using Exponential Decline Curve Analysis, the production profile is made for **WELL – 15**, her e decline trend is considered from May – 07







Remark: Same decline rate is taken for FTHP.

By considering Np value of WELL – 15 since inception i.e. 361210 m^3. The predicted cumulative oil production from WELL – 15 is 371810 m^3.

Sand 18-W can be further exploited, sufficient reserves were present. 0.72 MMT

From Decline Curve Analysis -Exponential Reservoir Production Life is Projected and Pressure Projection Rate is also Predicted.

Output

Original Oil In Place (N) = 1.2 MMT

Water Influx (W_e) = 108780.982 m3

Recovery Factor (R_f) = 30 %

CASE STUDY 2

Objective: To determine Gas cap zone size and Oil Initial In Place for Sand C.

The PVT data for Sand C is given below:

Pressure (psia)	Boi	Bo	Rs	Rsi	Rp	Bg	Bgi	Np
2498.454	1.424	1.425	116	116	180	0.0071	0.0065	3579
2454.372	1.426	1.424	110	114	310	0.0086	0.0072	36590
1999.332	1.39	1.362	90	96	380	0.0117	0.0096	531372
1498.788	1.35	1.307	69	75	410	0.017	0.014	630460

Using the technique of Straight line method, the material balance for a gascap drive reservoir can be expressed as

F = N (Eo + mEg)

The above Straight-line equation can also be expressed as

F = Np x (Bo + (Rp - Rs) x Bg)

= 3579 x (1.425 + (180-116) x 0.0071 = 6726.37 MM rb

$$E_o = \frac{(Bo - Boi) + (Rsi - Rs)Bg}{Boi}$$

$$= \frac{(1.425 - 1.424) + (116 - 116)0.0071}{1.424} = 0.0007 \text{ rb/stb}$$

$$E_g = \frac{Bg}{Bgi} - 1$$

$$= \frac{0.0071}{0.0065} - 1 = 0.09231 \text{ rb/stb}$$

The values obtained by PVT analysis data

N = 1200000 tons or 1.2 MMt

F (MM rb)	Eo (rb/stb)	Eg (rb/stb)
6726.3726	0.000702247	0.092307692
115038.96	0.022720898	0.194444444
2526673.86	0.030359712	0.21875
4478787.84	0.043703704	0.214285714

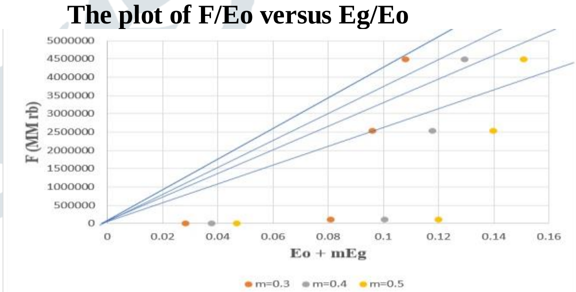
Evaluating (Eo + mEg) at different m values

Eo + mEg			
m = 0.2	**m = 0.3**	**m = 0.4**	**m = 0.5**
0.039591136	0.028394555	0.037625324	0.046856093
0.066470898	0.081054231	0.100498675	0.11994312
0.073216855	0.095984712	0.117859712	0.139734712
0.043703704	0.107989418	0.129417989	0.150846561

Different values of F/Eo and Eg/Eo are calculated for various Eo and Eg values.

F/Eo	Eg/Eo
9578354.582	131.4461538
5063134.474	8.557956104
83224565.53	7.205272512
102480738.7	4.9031477

The plot of F/Eo versus Eg/Eo



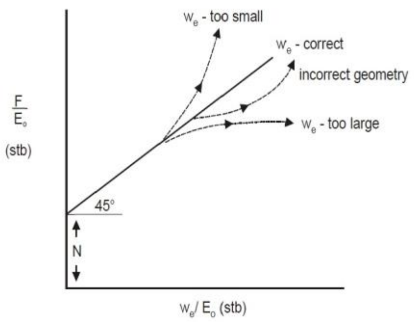
The plot for m = 0.5 intersects with the required straight line. So, we assumed that Gas cap zone size is 0.5.

Output

N = 8000000 m3 = **0.7 MMT**

Recovery Factor = Np / N = 630460 / 8000000 = 0.07 x 100 = **7 %**

Gas cap zone size **(m) = 0.5**



Case Study-3

Objective: To determine Oil Initially In Place (OIIP) and W_e (Water Encroachment / Water Influx) for sand -W using existing PVT data, till date wells production data.

In Sand -W already four wells have been drilled and are under production since feb-2010 to till date. Using the PVT data and production data using the methods material balance method and decline curve analysis.

The PVT data for three wells are,

well name	Bo	h, meters	Ø	So
WELL- 6	1.23	5	0.25	0.72
WELL- 9	1.15	5	0.27	0.7
WELL- 15	1.24	5	0.23	0.8

The PVT data of sand 17-W,

Rsi	Rs	Rp	Np	Wp
102	102	90	978	279.74
102	102	90	33863	14236.22
102	102	113	36590	14900.12
101.3	101	211	63130	27042.02
93.5	92.6	198	132668	57550.13
91.6	89.7	118	191733	94358.01
90.3	88.4	125	641372	337115.07

Bubble point pressure = 2375 psi.
Reservoir Temperature = 230^0 F
Formation Compressibility $C_f = 3.32 \times 10^{-6}$
$C_w = 7.22 \times 10^{-5}$ psi
The primary drive mechanism in Sand -W reservoir is **Water drive**
To Evaluate
Using the technique of Havlena and Odeh (assuming that Bw = 1), the material balance can be expressed as $F = N_p (B_o + B_g (R_p – R_s)) + W_p$
To calculate B_g Gas Formation Volume Factor

$B_g = \frac{ZT}{P}\ 0.02827$

Consider Z = 0.89; T = 230^0 F = 230 + 460 = 690^0 C

$B_g = \frac{0.89 \times 690}{2501.298} \times 0.02827 = 6.9406 \times 10^{-3}$

$B_g = \frac{0.89 \times 690}{2482.812} \times 0.02827 = 6.9923 \times 10^{-3}$

Now evaluating $F = N_p\ (B_o + B_g (R_p – R_s)) + W_p$

$E_o = (B_{oi} + B_o) + B_g (R_{si} - R_s)$

F	Eo	F/Eo
3411.29	0.003	1137097
87237.88	0.004	21809469
301572.9	0.002	1.51E+08
1405113	0.01024	1.37E+08
2007654	0.03632	55276824

We10	W10/Eo	We 20	We 30	We 40	We20/Eo	We30/Eo	We40/Eo
189	63000	6484.069	9795.093	13106.12	2161356	3265031	4368705
236	59000	8055.965	12169.66	16283.36	2013991	3042415	4070839
161	80500	5501.634	8310.988	11120.34	2750817	4155494	5560170
254	24804.69	8645.162	13060.12	17474.82	844254.1	1275403	1706525
138	3799.559	5894.428	8904.63	11914.65	162291.5	245171.5	328046.5

Drainage Area (A_D) = $\frac{EUR \times B_o}{\emptyset \times h \times S_o \times R_f} = \frac{641372 \times 1.3611}{0.27 \times 7 \times 0.7 \times 0.3} =$ 2199474.5 m^2
Πr^2 = 2199474.5, r_o = 836.9 m
$r_{aq} = \left(\frac{230944822.5}{3.14}\right)^{0.5}$ = 2711.997 m
Reservoir Volume = A x h = 2199474.5 x 7 = 15396321.5 m^2
$\frac{\text{Reservoir Volume x 15}}{10}$ = 23094482.25

$W_e = (C_w + C_f) \times Ø \times h \times \pi \times f \times (r_{aq}^2 – r_o^2) \times \Delta P$
$= (7.22 \times 10^{-5}) + (3.22 \times 10^{-6}) \times 0.27 \times 7 \times 3.14 \times 1 \times (2711.977^2 – 836.9^2) \times 66.834$
= 284749.4553

We = Cw+Cf*Ø*h*π*(Raq2 - Ro2)*ΔP	F/Eo	We/Eo
284749.4553	199336.3282	35154253.75
151462.4762	4918323.693	12214715.83
102994.4838	4971641.094	7152394.712
24233.9962	13351565.11	1909019.487
60584.9905	19680910.29	3450322.02
48467.9924	26944112.31	4535646.653
6058.49905	72687374.02	316272.8924

F/Eo	We/Eo
199336.3282	7534613.481
4918323.693	4283792.347
11101741.09	8240983.507
13351565.11	3917330.738
19680910.29	2445853.387

Considering f (Water Encroachment Angle) = 0.5, increasing reservoir volume V_r 10 Times, , increasing ΔP by 20%

A plot between F/Eo and W/Eo is drawn

If the aquifer model is correct, A Straight line with slope of 45^0 and joining two or more data points is drawn and We/Eo = 0. If the aquifer model is incorrect, the plotted data points will deviate from the theoretical straight line which has a slope of 45° and intercept N, when We/Eo = 0,

Hence the N = 3.2 MMT = 4000000 m^3

Water Drive Recovery Factor is 60 %.

Sand -W can be further exploited, sufficient reserves were present. 3.2MMT

Results

Six Case Studies of different sands, the parameters are calculated are given below:

Sand -D

Original Oil In Place (N) = 1051342.932 m^3 (0.87 MMT)

Recovery Factor (R_f) = 30.2 %

Sand -W

Original Oil In Place (N) = 1.2 MMT

Water Influx (W_e) = 108780.982 m^3

Recovery Factor (R_f) = 30 %

Sand -G

GIIP (Gas Initial In Place) = 800 MMm^3

Recovery Factor (R_f) = 78.46 %

Well test analysis

Permeability =77.96158815 MD

Skin factor =6.24

Flow efficiency =54.7

Decline Curve Analysis –

We observed that decline rate was fast in Sand – D

Decline production rate was faster in two sands Sand – D, Sand – G lesser in Sand-W.

Indicated that Sand – D and Sand -G are in mature stage of production Sand – W still has flow to be p

CONCLUSION

.This project main aim is to study and evaluate the three types of sands namely sand-d, sand-w, sand-g. Each sand has different drive mechanisms. Sand-w is purely water drive mechanism. In water drive mechanism in which oil is produced by the expansion of the underlying water and rock, which forces the oil into the wellbore. In sand-w the decline production rate was lesser as compared to sand-d and sand-g. Sand-w has still flow to be produced. In sand-d decline curve was fast and this is the depletion drive mechanism/solution gas drive mechanism. In depletion drive use of energy that arises from the expansion of compressed gas in a reservoir to move crude oil to a well bore. Final sand is sand-d this is mature stage of production. In this sand-d reservoir temperature is considered to be constant. The compressibility factor for standard conditions is assumed to be 1.

References

1. Ahmed, T., "**A Practical Equation of State**," *SPERE*, Feb. 1991, Vol. 291.
2. Amyx, J., Bass, D., and Whitney, R., "**Petroleum Reservoir Engineering**". New York: McGraw-Hill Book Company, 1960.
3. Clark, N., **Elements of Petroleum Reservoirs**. Dallas: Society of Petroleum Engineers, 1960.
4. Thakur, G.C. and Abdus Satter, "**Integrated Petroleum Reservoir Management**: **A Team Approach**", Jan. 1994
5. Frank W. Cole., "**Reservoir Engineering Manual**," Texas: Gulf Publishing Company,
6. L.P. Dake, Text Book on "**Fundamentals of Reservoir Engineering**" October 1977.
7. L.P. Dake, Text Book on "**Practice of Reservoir Engineering (Revised Edition)"** 2001.
8. WADSLEY A. W (2011) Markov Chain "**Methods for Reserves Estimation"**. International Petroleum Technology Conference. Doha, 2005.
9. ROBERT KOSOVA., "**Deterministic and Stochastic Methods of Oilfield Reserves Estimation: A Case Study from Ka. Oilfield**" 1-st International Scientific Conference on Professional Sciences, "Alexander Moisiu" University, Durres November 2016